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“Hydraulic Fracturing Efficiency in the Olmos Sand Formation”

by

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Undergraduate honors thesis under the direction of

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Submitted to the LSU Honors College in partial fulfillment of
the Upper Division Honors Program.

December, 2010

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Abstract

In order to produce hydrocarbons from tight sandstone formations with low porosity and permeability, hydraulic fracturing techniques must be used. Certain types of hydraulic fracture treatments are more efficient than others at increasing natural gas production. The goal of this project was to find the most effective fracturing technique for use in Swift Energy Company's AWP natural gas field through a look back at historical fractures and gas production. This study considered efficiency to be measured by the gas production produced in the 180 days following treatment, normalized on the product of porosity and sand thickness (Φh), as well as incremental production caused by a well's second fracture. These incremental production values to the cost of the fractures were used to find average values for the return on investment (ROI) for each type of fracture. For the wells selected, hybrid fractures created a greater gas production compared to the cost of the fracture.

Introduction

History of the Field

The A.W.P. Olmos Field is located in McMullen County, Texas (**Fig. 1**) and gas produces from the Olmos sand (through the Campanian stage of the Upper Cretaceous) in 1981 with the field discovery well, the Burnett Oil Co. No. 1 Elliot. This field is about 100 square miles in area, and in January of 1987, there were 267 producing wells, which were producing from a hydrocarbon column of 2000 ft. Some sections of the Olmos formation have porosity values of as low as 9 percent from the density log, but most operators will not drill a well unless the target area has a predicted porosity of at least 15 percent.[1]

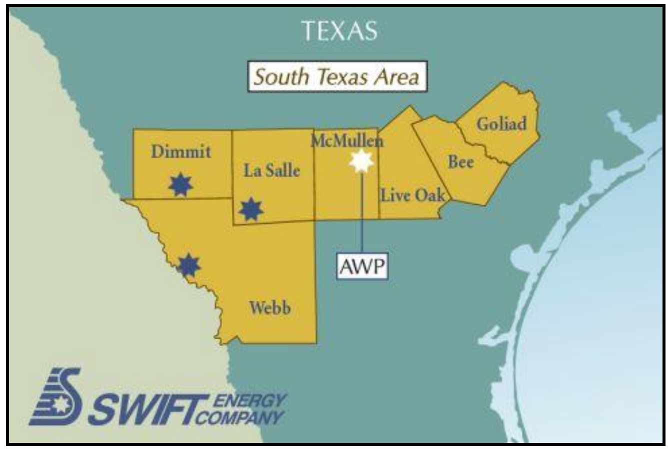


Figure 1. Location of the AWP natural gas field in McMullen County, Texas. The focus of our project is on the AWP Lease of the AWP field, which is a part of the Olmos Sand Formation. Source: *http://www.swiftenergy.com*.

The productive areas of the Olmos Formation are divided into five depositional zones, with seven exploration and production plays. The AWP field is considered in the shelf-edge trap play of the Olmos formation.[2] Within the AWP field is a lease called the SBR; all wells considered in the study came from this lease and data was provided by Swift Energy.

Because the Olmos formation is a tight, low-permeability sand of 0.1 millidarcy or less that is about 10,000 ft deep, it can be rather difficult to produce without the proper technique.[3] Formation bottom-hole temperatures extend to 259ºF.[4] Oil and gas will not flow naturally, so the formation has to be hydraulically fractured. Wells were not productive in the area until the late 1970s, because the fracturing technology at the time was not adequate. Because the fracturing techniques have been improved, it was predicted that this play would have significant potential in the future.[2] During the late 1980's, it was more profitable to re-stimulate these wells, rather than to drill new wells.

Swift Energy Company began to fracture the formation around 1980. In the AWP field, the most common fracture treatments are water and gel fractures, followed by diesel and hybrid fractures. The hybrid fractures used are a combination of slick water and sand laden gel fractures.

The historical data of fractures in the SBR Lease show trends of fluid types used since fracturing began on the lease in 1995. From June 1995 to November 1997, first and second fractures were exclusively gel fractures. There were 170 gel first fractures and 14 gel second fractures. From

November 1997 to December 2000, the primary fracturing fluid was water, with 16 first water fractures and 132 second water fractures. Next, Swift tried a variety of fluid types on the well fractures from January 2001 to June 2004, which included gel, hybrid, diesel, water and CO_2 fractures. After this, from September 2004 to September 2009, all fractures were done with water, with 26 first fractures and 37 second fractures. Any third or fourth fractures in this field were water or hybrid. This shows that gel was the first fluid tried in these wells, but after experimentation with other types of fluids, they have since moved on to mostly water fractures for initial and refracturing techniques.

Early in the field's production, companies utilized over a million lbs of 20/40 mesh Ottawa sand in their fracture treatments. While these sands produced good results and compensated for the loss of conductivity, it also caused many mechanical problems such as proppant flow back into the wellbore. Economic factors also played a role in trying to find an alternative way for fracture treatments. As oil and gas prices fell in the 1980's, smaller volume jobs were attempted, but the production was not as good as the larger volume fracture treatments and required quicker refracture treatments.[10] To try to fix the continuing problem of wellbore inflow of proppant, they applied a combination of procured and curable resin coated sands (RCS) to try to minimize crushing, reduce embedment, and stop proppant flow back. "In excess of forty treatments have been pumped with a design average of 400,000 pounds of RCS. The higher cost of RCS was offset by treatment size reductions. The wells maintain better production than comparable offsets, with no proppant flow back."[10]

Geologic Setting

The Olmos formation is a diverse formation characterized mainly by shelf, shore-face, delta-system sandstones, and associated mudstones. The Olmos is a fine-grained sandstone, and its facies are analyzed using calibrated image logs because cores are not readily available for these sands. Cross-bedding and burrowing trace fossils are also commonly found in the image logs of the shore-face strata. In the delta-system sandstones, there are salt-marsh facies as well as channel facies. Cross-bedded sandstone usually dominates the channel facies of this section.[2] The effect of diagenetic effects such as burrowing and cross bedding have contributed to the homogeneity of the reservoir of this field, allowing expansion with reasonable certainty of the geologic features.

The entire AWP field is said to have similar geological properties, allowing comparison of these fracture types without geologic variability affecting the results. To verify this, average net pay and porosity are sketched on a section map for the lease **(Fig. 2)**. Seventeen sections have producing wells, and the trend seems to be higher porosity further updip and thicker pay further downdip. This is an interesting trend, but does not conflict with the ability to compare the fractures and production of the wells. While the values varied, averages remained around 14.8 percent (with a standard deviation of 1.1 percent) and a net pay thickness of 44 feet (with a standard deviation of 14 feet). While the net pay thickness does vary, the similar porosity for the field allows for reasonable comparisons of performance of wells. Normalizing values based on the porosity and thickness where necessary eliminates problems associated with comparing different wells.

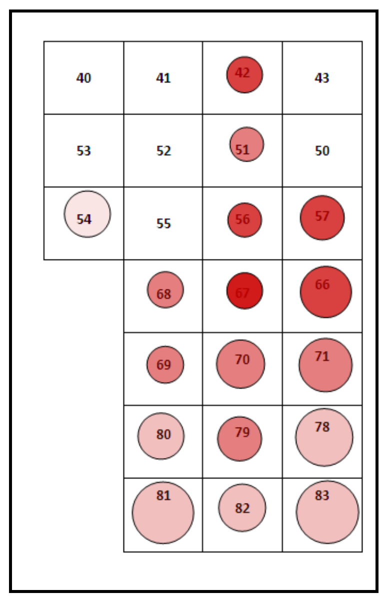


Figure 2. A map of the section numbers with producing wells in the SBR Lease of the AWP Field in McMullen County. Size of the circle indicates the average net pay value of wells in that section with a cutoff of 10 percent porosity. Shading indicates average porosity, with darker shading representing a higher porosity. Generally for the field, the porosity is higher further north, but net pay averages higher in the southern sections.

The shelf-edge trap that the AWP field produces from is distally deposited sandstone, which has

been reworked and tilted after compaction. This area is known as the Big Foot delta[2], and actually is referred to as a "textbook example of a regressive deltaic sand sequence."[11] The porosity of the entire reservoir ranges from 10 percent to 28 percent and is on average 18 percent in the producing interval.[12] The cut-off for net pay consideration by Swift Energy is 10 percent porosity. The permeability gradually decreases from one millidarcy up-dip to 0.01 millidarcy down dip because of the high clay content in the latter section. [13]

The Fracturing Process

Hydraulic fracturing is necessary because the natural porosity and permeability of the sandstone do not allow for flow of hydrocarbons naturally. Fracturing creates channels of high permeability to bring fluids from the edges of the reservoir to the wellbore. During hydraulic fracturing, gel-like fluids are pumped down into the wellbore at high pressures. This causes the formation to fracture and release hydrocarbons. After the formation has been fractured, proppants are used to hold the formation open so that the hydrocarbons have an unrestricted flow path to the surface for production. A basic hypothesis in fracturing is that production is a function of effective fracture length and effective fracture conductivity. If this is true, higher viscosity fluids such as gel led fluids carrying high amounts of proppant should provide greater hydrocarbon production than a water fracture, which has a lower viscosity and is unable to carry as much proppant. This all is assuming that the treatment stays within zone, the fracture face is not severely damaged, and the fracture fluid breaks and cleans up properly. Although this is true, industry has moved to water fractures rather than gel fractures for tight gas sands because water fracturing treatments cost less and achieve comparable production to underperforming gel fracture treatments[5]. This can be seen in the historical records for production in the SBR lease by Swift Energy. For tighter rocks, as with the Olmos sandstone, it is most desirable to have a longer fracture length with moderate flow capacity.[6]

Proppant: Fracturing Solids

One of the main problems associated with fracturing is proppant flow back—after the fracturing treatment is complete up to 20 percent of the proppant can flow back into the wellbore and cause damage to production equipment.[7] In order to reduce the amount of proppant that flows back into the wellbore, flow rates can be reduced and a special type of proppant can be used. Curable resin-coated proppants (RCP) can be pumped into the fracture at the tail-end of the run to create a strong pack that can withstand impressive amounts of stress, shut-in time, and temperature. One major disadvantage of using RCP is that it can interact with the fluid to change pH, breaker efficiency, and cross link success. Also, the well must be shut-in overnight so that the RCP can cure, and then the proppant must be activated by low temperatures.

Because RCP can cause many problems, the need for a new proppant technology has arisen. Small fibers have been used to try to bind the proppant together, and heat-sensitive plastic film has also been used to capture proppant clusters.[8] These methods seem to be fairly successful, but their effects on conductivity have caused some people to be concerned because the fibers and plastic films occupy potential pore space which blocks the gas flow path. To try to battle the loss of conductivity, deformable isometric particles (DIP's) can be added to the mix. These DIP's are slightly larger than the proppant particles, so the proppant tends to surround the DIP's and form tight packs.

These embedded packs help to prevent flow back and keep the proppant particles from being crushed or broken.[8] Overall, the curable RCP is still considered to be the safest and most efficient method way to control flowback.[8]

Another problem associated with fracturing in these high-temperature, high-pressure areas is the ability to keep the fractures open. Because of the high compressive stresses, the proppant can get crushed, which leads to inadequate flow. For reservoirs at 10,000 feet, this means that very narrow fractures are likely to fail.[6]

Fracturing Fluid

The types and uses of hydraulic fracturing fluids have evolved significantly over the past years and are continuing to evolve. The main fluid categories used in the industry are gelled fluids (including linear or cross-linked gels), foamed gels, plain water and potassium chloride (KCL) water, acids, and combination treatments[9]. The AWP wells mainly use gelled fluids, water, and diesel for fracturing treatments. Each type of fracturing fluid has unique characteristics, and each has

advantages and disadvantages associated with its performance traits. For ideal performance, fracturing fluids should possess the following four qualities:

1. Be viscous enough to create a fracture of adequate width
2. Maximize fluid travel distance to extend fracture length
3. Be able to transport large amounts of proppant into the fracture,
4. Require minimal gelling agent to allow for easier degradation or "breaking" and reduced cost. [9]

In order for a gel to perform well in deep wells, it must also have these properties:

- Low friction pressure
- Stability above 450ºF
- Non-damaging
- Compatible with other salts used
- Fracture viscosity that is independent of surface viscosity
- Support proppant for transfer into the fracture.[6]

Larger proppant volumes allow for wider fractures, which allows for a faster flow back to the production well. In some tests, the high-viscosity fluids were able to carry twice as much proppant (in pounds per gallon) downhole, when compared to the low-viscosity fluids. Higher-viscosity fracturing fluids are also an advantage in that their fracture tunnels remain open, over the low-viscosity fluid.

Water fracture treatments are usually the cheapest because service companies can use groundwater pumped directly from the formation or treated water for the fracturing job. Production performance is not generally as good with just water, but in some cases water fracture treatments have achieved adequate production rates. However water alone is not always enough for certain formations because its low viscosity limits its ability to transport proppant.[9]

Diesel fuel is frequently used instead of water because its viscosity and thus carry capacity per unit volume is much higher. However, diesel does not enhance the efficiency of the fracturing fluids; it just helps the delivery system. To fix both of these problems, cross-linked fluids/gels were created.

Cross linked gels – which include polymers to increase the viscosity - have been a major advance in fracturing fluid technology. Cross-linking reduces the need to add fluid thickener and extends the viscosity of the fluid indefinitely. Although this process is more expensive, it can greatly improve the performance of the hydraulic fracture, therefore increasing well production rates making up for the extra expense.[9]

Swift Energy has recently experimented with hybrid fractures. The design of their hybrid fractures uses a two percent KCl water as the base fluid. They start with a slick water pad (a mixture that combines water with a friction-reducing chemical additive) followed by a sand laden slick water pad. They then pump two sand laden gel pads which include friction reducers, slurried gelling agents, breakers, and cross linkers. They finish with a slick water flush. This takes the positives of both water and gel fractures and combines them for a better overall fracture treatment.

Although the technology is available, not all wells are possible candidates for stimulation. The best candidate for refracturing is a well that has sufficient gas in place, but is producing at a low rate. This can easily be justified, by analyzing the expected increase in production. Another candidate is a well that has been depleted over its lifetime. In this case, a refracture would allow the gas to produce faster and be recovered sooner. Stimulation should be evaluated to look at both accelerating the gas recovery and increasing the amount of gas that is recoverable. Decisions on stimulation treatments should be made based on all known information of the well, particularly the predicted production increase based on fracture length. With the information on flow capacity, drainage radius, economic limit, and fracture costs of various lengths, the best design for a fracture program can be chosen.[6]

Refracturing has become a common procedure for wells in the AWP Field for Swift Energy. This was discovered in 1998 and 1999 when drilling programs were curtailed because of low gas prices (**Fig. A1**). Refracturing wells for increased production was cheaper than drilling new wells, and this was found to be very successful for most of the wells. When the well has already been fractured, and depleted some, the reservoir pressure has been reduced, allowing for smaller volumes of fluid and sand to create larger flow paths than those of the initial fracture. After this discovery, Swift Energy incorporated the technique into their drilling program. Smaller, first fractures would be used as "sacrificial fractures" for the initial

completion of the well. After several months, which allowed for data collection and formation of an appropriate fracture program, a second fracture would be performed. This specialization of each second fracture for the particular reservoir conditions, along with using water fractures with only ordinary sand resulted in fracture costs that were half of the original costs of fractures in the field.[14]

Historical Fracturing Evaluation

Setup Information and Wells

The information provided on historical wells was a list of 232 wells in the SBR Lease of the AWP Field. Data included physical reservoir parameters (such as height and porosity), treatment volumes, and 180-day cumulative natural gas production for each of the fractures (up to four) performed on the wells in the lease. This master well list helped to identify potential trend lines on which to base the study, as well as important reservoir parameters and fracture frequency in the AWP field. After analyzing the data, twenty-four wells were selected to further study. This was done by a using a grid system based on normalized fluid volume pumped and 180-day cumulative production to get a balanced set of data (**Fig. 3**). The data was normalized between wells by dividing by the porosity and net pay (with a 10 percent porosity cutoff) for each well. This selection of wells helped to accurately determine the effectiveness of four different types of fracturing technologies used in the area: water, gel, hybrid, and diesel fractures. The grid ensures that we sample a mix of successful, unsuccessful, and mixed fracture treatments.

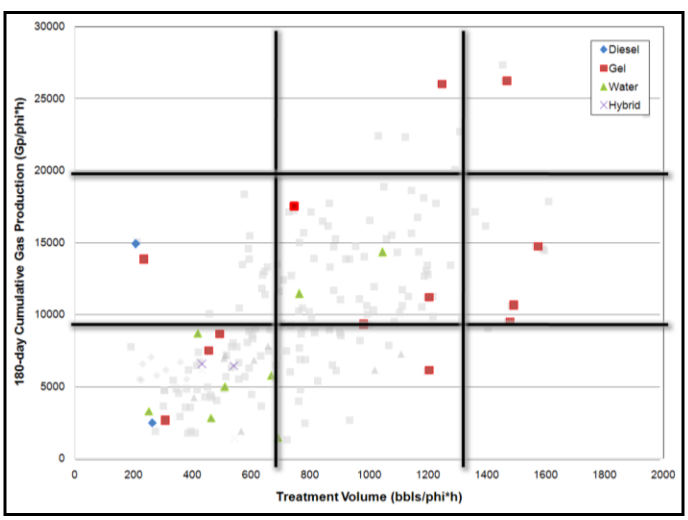


Figure 3. Plot of the normalized 180-day cumulative production following fracture vs. treatment volume. We selected a range of wells (represented by the colored data points) from the grid on this plot in order to narrow down the study from 232 wells to 24 wells. Blue points represented diesel first fractures, red represent gel, green represents water, and purple represents hybrid.

The wells selected in the lower left, middle, and top right squares represent those that performed successfully, as there was a direct relationship between the treatment volume and the cumulative production response to the fracture. Each type of fluid was chosen for study in these squares, to further investigate the effect of different fluid types. Another consideration in choosing the wells was to evaluate those wells that have similar treatment volumes, but different cumulative production after treatment, and vice-versa. For example, the there are two wells in the center square which have about 800 bbls of normalized treatment volume. The gel fracture has a much higher cumulative production than the water fracture. This is a start to the hypothesis that the gel fractures are more effective than water fractures in some cases.
For these chosen wells, Swift Energy provided more information including historical production of gas for the life of the well, detailed fracture data including fluids and sand used, costs, and daily drilling reports.

Production Profiles and Declines

Using this data, we graphed historical production profiles for each well, which show the daily production of each well before and after two or more fracture treatments. Using this data and the equation for the hyperbolic decline curve, future production rates were calculated and graphed (**Eq. 1**). The hyperbolic decline rate was chosen because it fit the historical data the best, which makes it reasonable that the future production of the wells would average to follow along this production profile.

$$q = \frac{q_0}{(1 + ntD)^{\frac{1}{n}}}$$

Equation 1. The hyperbolically declining flow rate (*q*) used in our forecast is defined by the initial flow rate (q_0), the decline exponent (*n*), time (*t*), and the decline constant (*D*).

In completing the decline curve analysis, first the

historical production data was plotted. One of the complications that arose with decline analysis was the zero values that were listed for daily production because of shut-in time, workover time, or unavailable data. After these were eliminated, the rate calculated from Equation 1 was compared to the actual production rate through February 2010. Using the least squared approach and spreadsheet capabilities, the sum of squared errors between the calculated rate and the actual rate was reduced as much as possible by adjusting the initial flow rate, the decline exponent, and the decline constant (**Fig. A2**).

The production of all 24 wells was calculated out for thirty years after the last fracture date for each well. This value was chosen because an average life of a well in the Olmos Field is about 30 years. Predicted declines for each fracture were forecasted for this entire time, to show the improved production rate between the initial fracture and the refracture. First fracture values were the best available to use as a control because there is no production data before a fracture. Hydrocarbons do not flow before hydraulic fracturing and fracturing is done soon after completion of drilling of the well.

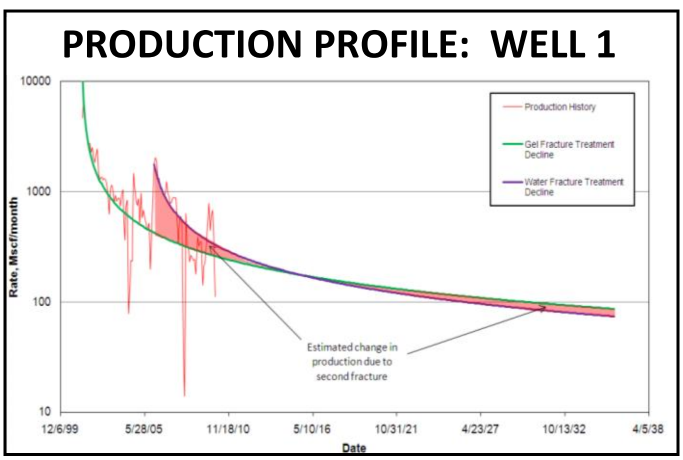


Figure 4. The production profile for the first case study (Well 1) shows that a water fracture treatment causes a faster decline in gas production than a gel fracture treatment. The incremental production is noted by the shaded red areas, and in this case the incremental production between the first and second fractures becomes negative after approximately 10 years.

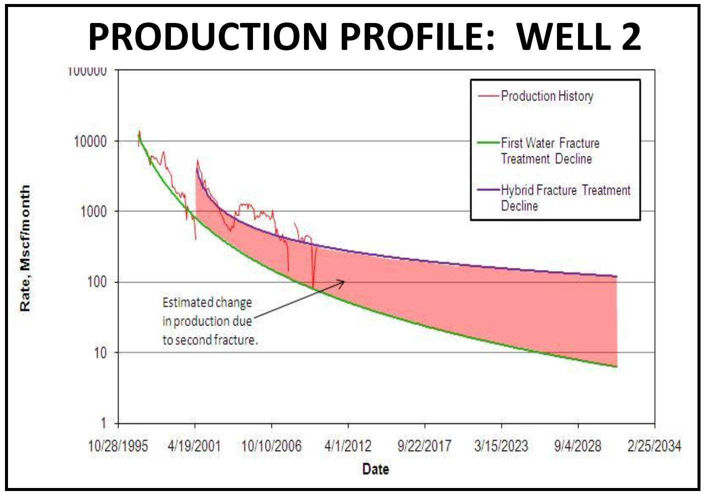
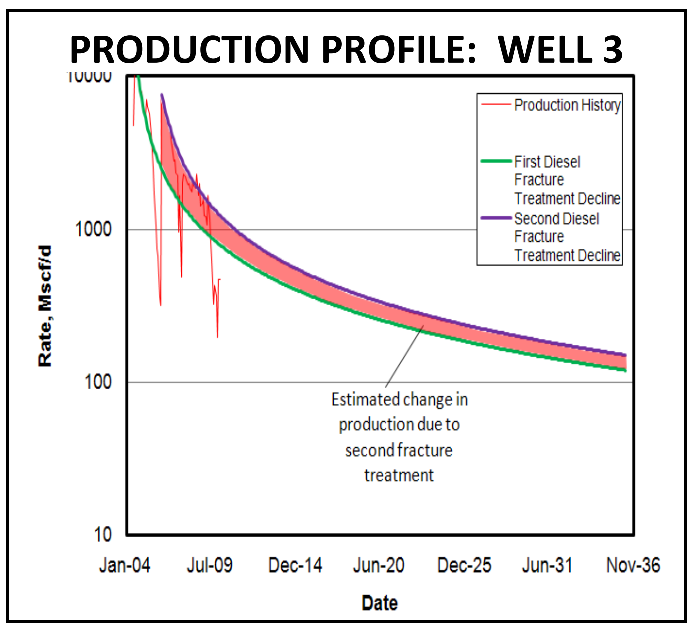


Figure 5: The production profile for the second case study (Well 2) shows that a hybrid fracture treatment causes a slower decline than a water fracture treatment. The incremental production noted by the shaded red areas, is positive for all future forecasts.

The red area shown in the graphs is the estimated increased production rate due to the second fracture for the life of the well (**Fig. 4**, **5, and 6**). Using the difference in calculated monthly production rates, a cumulative volume was calculated for the sixty months following the last fracture, to determine a standard increased production value for each well.



Figures 6. The production profile for the third case study (well 3), shows that the decline rate for diesel fractured wells is consistent, although a greater production may be encountered because of an increase in the drainage area. The incremental production is noted by the shaded red areas, and is positive.

Economic Evaluation

To compare profitability of the jobs, a value of return on investment (ROI) was estimated based on the calculated incremental gas volumes, job costs, and the average natural gas price for the time period which was $3.50/Mscf (**Fig. 7**). An average gas price was used to evaluate conservatively and to not give favor to those jobs occurring in high gas times. Although price of treatments does increase as price of gas does, it is not at the same time and would interfere with the results incorrectly.

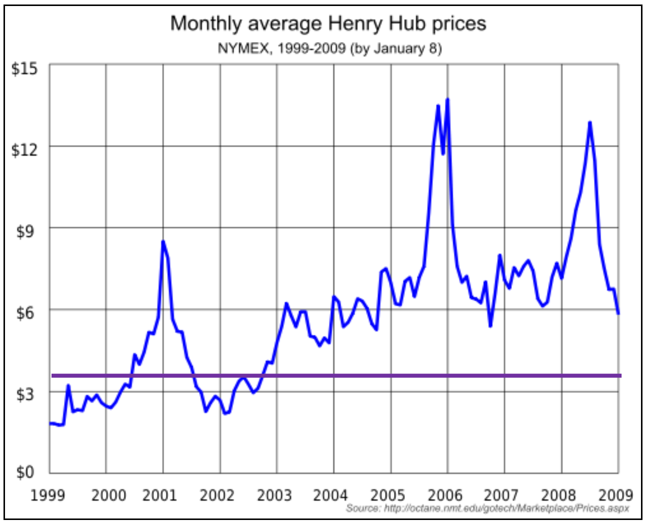


Figure 7: The historical natural gas prices from Henry Hub from 1999 to 2009. SBR wells were refractured starting in 1998 and further development of the field extended through this time. The horizontal line represents $3.50/Mscf, which was the price of gas used in the economic evaluation. Source: http://octane.nmt.edu/gotech/Marketplace/Prices.aspx

A chart comparing the average return on investment (ROI) vales for each type of fracture treatment clearly shows that hybrid fractures created the highest increase in profit for the amount of money invested (**Fig. 8**). ROI was calculated by dividing the profit for 60 months (value of total incremental production less the job cost for the well) by the total cost of the fracture treatment for each category of fractures. While gel fractures have a high gas production value, they also have a very high job cost total, which brings the ROI down so much (**Fig. A5**).

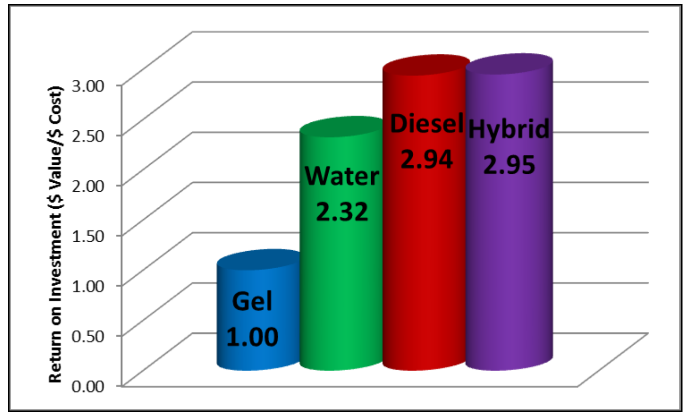


Figure 8. Bar graph comparing return on investment values for each type of fracture technology. Average ROI values were computed by dividing the sum of incremental profit of the fluid type by the sum of job costs for the fluid type. This graph shows that hybrid fractures create the highest average ROI in the AWP field, followed very closely by the one diesel fracture in the study. See **Figure A3** for all values.

Discussion

In observing these production declines for wells in the AWP field, an increase in production is observed for some wells long after the last fracture date (**Fig. 9**). In this well, the production was declining steadily, producing at about 1400 MCFD in October 2004. In November 2004, the rate rose to 1600 MCFD and continued along this rate, reaching up to 1800 MCFD in March 2007. These are not increases in production due to workover jobs or additional fractures.

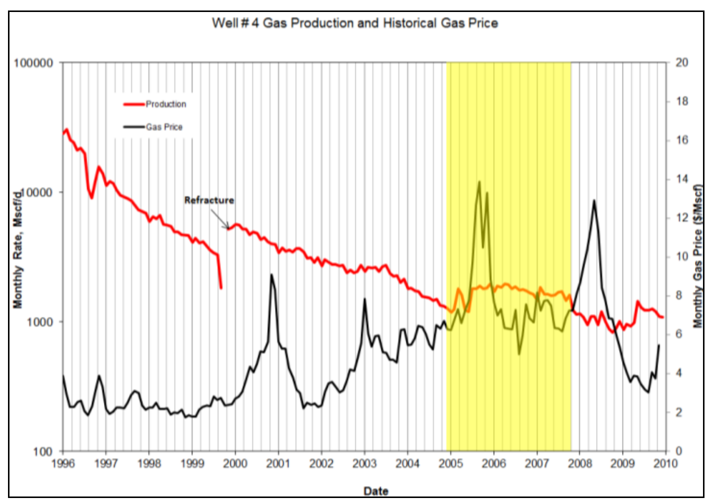


Figure 9: Historical monthly production decline for a well in the AWP field from 1996 to 2010. A refracture in 1999 increases the initial production rate and continues along a decline. The fluctuations seen in 2005 and after (highlighted area) seem to be closely tied to gas price. Likely this was an operational change to produce more gas during times of high prices.

An explanation of this increase can be seen when looking at the gas price for this time. The increase in the well's production occurs at the same time that the price of gas rose to $13/mscf. Because of this, it is likely that the increase in production is due to operational changes made at the surface to produce more gas while the price was high. The same response does not happen in June of 2008 when the gas price spiked at $12/mscf. A look at the other fluids produced in this field could give an explanation to that (**Fig. 10**).

In 2006 and 2007, the well begins seems to have its first real problem with water production. During the time of the gas spike in 2008, the operators look like they were trying to control water production, so they did not want to increase the gas rate too much. The cyclic increase and decrease of gas shown in 2008 suggests that the operators were trying different production rates on this well to find optimal operating conditions. In 2009, the operators went back to a rate similar to that in 2007, and allowed the water and condensate to increase with it.

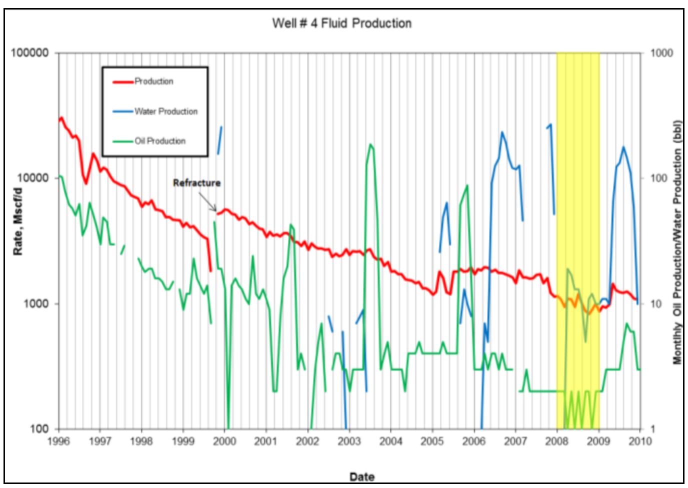


Figure 10: Historical monthly production profiles for the same well in AWP field. While the gas rate in 2008 (highlighted area) does not follow the increase in price at that time, it does seem like the operators were trying to control the water and optimize the gas and condensate production from the well.

Condensate production is a significant product and revenue source of the AWP Field, so it would make sense that the operators were trying to determine the best operational settings to reduce the amount of water and optimize the amount of oil and gas produced.

Other reasons that could contribute to unusual changes in the decline profile include surface facility changes, shut-in periods, and interference in the subsurface. Changes in the surface facilities could improve the production without requiring a workover downhole. If the wells here are shut in due to maintenance or too low of gas prices, the average monthly rate would be decreased. After this time, the rate would be a little higher, producing from built up pressure in the reservoir during shut-in time. Because the wells in the SBR lease are spaced very closely together, interference between wells is a very likely factor. On the negative side, new wells could interfere and produce from another well's area, lowering the production of the initial well. On the positive side, so many fractures in the formation could allow for better flow throughout the reservoir, which would increase production of the wells.

From the results of decline curve analysis presented in the last section, some points can be made about the types of fluid used on wells. As each of these wells was analyzed for incremental production, it is a safe evaluation to compare results between the wells.

Hybrid fractures create large fissures in the formation using water, and then these newly-created fractures are held open by proppant that has been distributed using gel. The gel allows for easier transport of the proppant because it has a higher viscosity than water, but the water produces larger fractures in the formation. This physical phenomenon explains why hybrid fractures usually produce more hydrocarbons from the reservoir after fracturing. The production profiles prove this (**Fig. 5**) because the hybrid fractures we researched have a usually had a lower decline constant, meaning the decline rates are lower than the other fracture types, as well as a generally lower decline exponent. This means that the well should be able to produce at an economic rate for a longer time period. Also, because hybrid fractures involve mostly slick water pads, followed by a gel pad, the cost is about the same as that of a gel fracture (**Fig. A6**), but the increased production makes up for this.

Only one diesel fracture was considered in this study (**Fig. 6**) as the second well chosen to represent diesel only had one initial fracture and thus could not be considered for incremental production. While this well was able to reach further reserves after refracturing, this is only one well considered, not an average. Also, while ROI is

great for the first five years of life, the overall life of the well does not seem to be extended greatly due to this fracture. Diesel fractures are the best treatments for an early return on investment – but do not perform well in the long-term life of the well.

Water fractures had the lowest average cost of all the types. While this is favorable, most of the production profiles with water as a second fracture would show an initial increase, followed by a decline that fell beneath the forecasted production of the initial fracture (**Fig. 4**). This especially showed on wells in which the length of time between the first and second fractures was greater. For this reason, water fractures should be kept as the initial sacrificial fracture that Swift has been using, but should not be considered as strongly as other types for a second fracture, because it will not provide much more drainage over the initial fracture.

Gel fractures were more expensive than water and diesel fractures, and their incremental production was not enough to overcome this as seen in **Figure 8.** While the wells would not see a large amount of increased production, these wells would be able to operate above an economic limit longer. This is an advantage because it would allow the well to produce for a longer life and recover more of the reserves.

Support of these discussions about performance versus fluid type can also be observed in the following figures. **Figure 11** shows 180-day cumulative production (after the first fracture) against the estimated ultimate recovery for the well. The three types of fluids for first fractures were diesel, gel, and water.

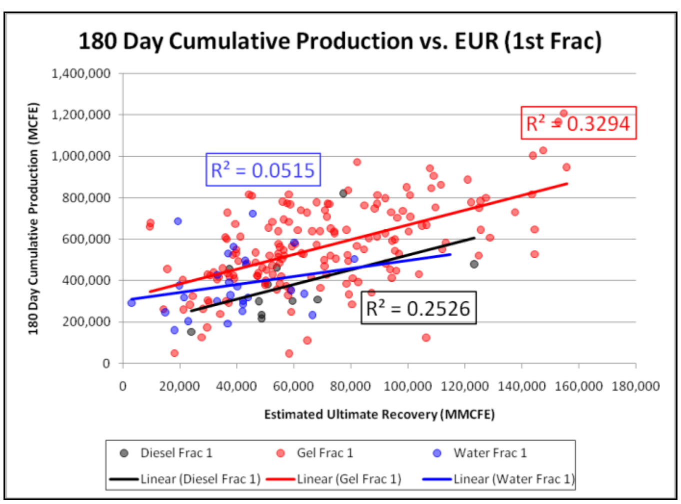


Figure 11: A comparison on 180 day cumulative production against estimated ultimate recovery, with linear trend lines for the first fractures in wells in the SBR lease.

This graph shows how well the fractures performed based upon the expected availability of gas for each well. While the trends are week as shown by the R^2 <<1, several notable points are apparent. Here water does not have much of an increased performance in the 180 days after the fracture, no matter the EUR of the well. The diesel fractures produced adequate cumulative production, but that is because this is a short term period, when diesel performs the best. The gel fractures performed well for the first fracture, giving the highest sloped trend line. Because these are first fractures, it seems that gel and diesel are better fluids to break the initial reservoir pressure found right after drilling a well.

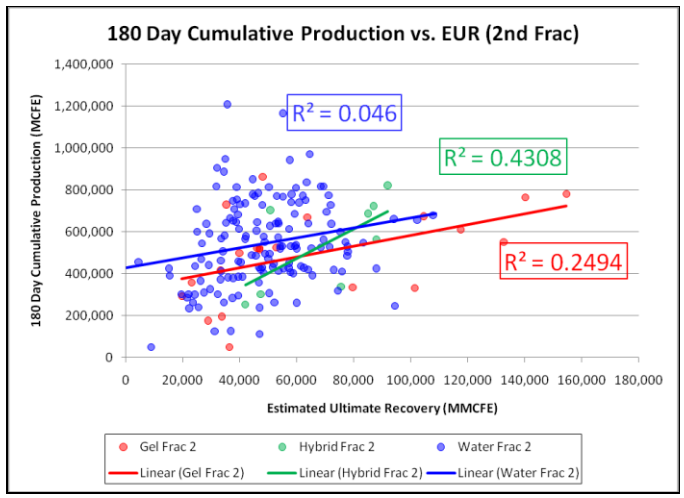


Figure 12: A comparison on 180 day cumulative production against estimated ultimate recovery, with linear trend lines for the second fractures in wells in the SBR lease.

In **Figure 12**, the fluids used for second fractures are gel, water, and a hybrid combination of gel and water. Hybrid has the best trend because of its high positive slope. Water and gel have very close declines, and here water outperforms gel as a fracturing fluid.

These graphs support the same conclusion as the decline curve analysis and ROI.

As stated before, fracture efficiency is a function of fracture half length and fracture conductivity. The fracture treatment needs to try to penetrate the formation further with fracture propogations, and be able to hold these fractures open with pumped proppant. When the initial production of the curve increased, but there was little to no change in the

decline constant and coefficient, this is representative of reaching further into the reservoir with fractures. The area is increased, which helps flow more gas to the well. This was seen in the diesel well as well as with several of the water fractures – especially those that used water for the first and second treatments.

When the second fracture produced rates that determined a different intial production, decline constant, and decline coeffcient, this improved (or worsened) the productivity index of the well. When this happened, the fracture half length was incrreaed, as well as the permeability and conductivity of the proppant-filled fractures. This was seen most often in the gel and hybrid fractures. This is what gave the wells fractured with gel and hybrid some of the better values of incremental production.

Also, the graphs of future declines of the wells that seemed to increase area and conductivity were more level for longer periods of time, allowing an extended economic life of the well.

From the trends of these graphs, Swift Energy should try to use hybrid fractures for their initial fractures to see how they do when encountering full reservoir pressure. If hybrid fractures perform as well as they do for the second fractures, then this may eliminate the need for sacrificial first fractures completed with water. If the hybrid fracture does not perform well as the initial fracture, it would still be the best choice overall for second fractures, to maximize the effectiveness of both fractures.

Conclusions

When hybrid fractures were compared to other types (water fractures, gel fractures, and diesel fractures), it was clear that hybrid had the highest average ROI, and the lowest post-fracture decline rate.

For these reasons, hybrid fractures show the most potential for profit generation when used in the AWP field of the Olmos Sand Formation.

Acknowledgements

C. D. White (Louisiana State University) provided technical guidance and support in reservoir engineering, production engineering, software use, and economics. A. Goodwin and J. Thames (Swift Energy Company) provided industry support and technical guidance in production engineering. S. O. Sears and W. Hull (Louisiana State University) provided critiques of our written, spoken, and visual communications. The initial project was completed as a team with research, curve-fitting, and graph preparation by L. Simoneaux and K. Barrett. S. Sears and J. Nunn (Louisiana State University) provided feedback and guidance for further investigation topics.

Nomenclature

Φ = formation porosity, percent
h = formation thickness, ft
q = flow rate, bbl/month
q_0 = initial flow rate, bbl/month
n = decline exponent
t = time, months
D = decline constant

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Appendix of Figures and Tables

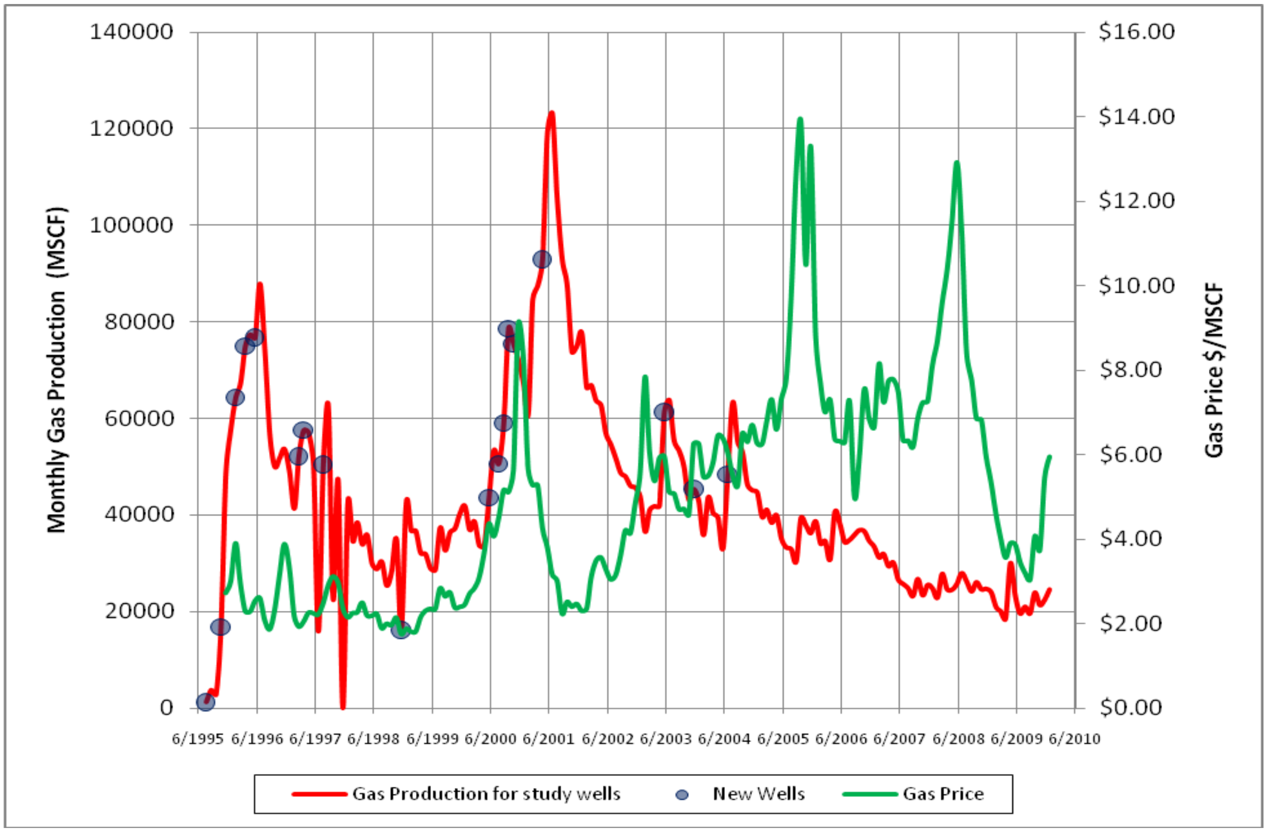
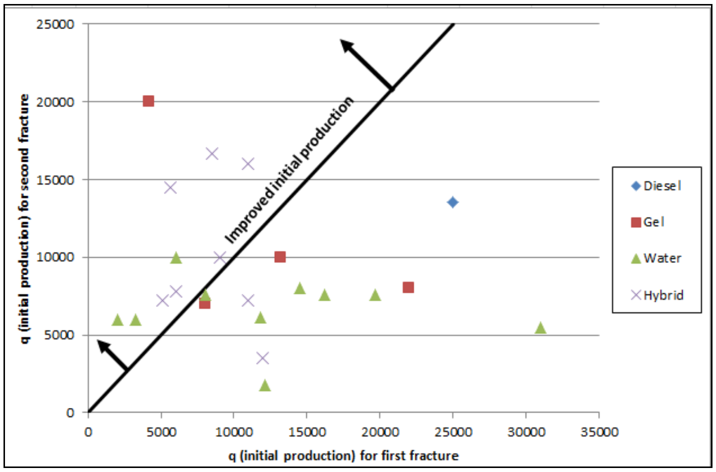


Figure A1: Green lines indicated the Henry Hub monthly gas price from 1995 to 2010. The red line is the total gas produced per month from the 24 wells in the study as these were the only available monthly productiond data. The blue points represent months in which a new well was put on production, sometimes more than one in a month. Spikes of production increased production from adding or refracturing wells occur after spikes of high gas prices such as in 2000-2001. When the gas price fell after this, the wells were probably cutailed and that explains the sharp decrease seen in 2002.

Fracture Fluid	$q_{0,1}$ bbl/month	$q_{0,2}$ bbl/month	n_2	$D_{first\ frac}$	$D_{second\ frac}$
Diesel	25000	13533	1.000	0.0014	0.0052
Gel	4168	20000	0.752	0.0382	0.0030
Gel	22000	8000	1.000	0.0066	0.0070
Gel	13201	10000	0.913	0.0034	0.0035
Gel	8024	7000	0.750	0.0017	0.0032
Hybrid	11000	7248	1.091	0.0010	0.0040
Hybrid	12000	3500	1.264	0.0010	0.0072
Hybrid	11000	16000	0.500	0.0010	0.0010
Hybrid	6000	7794	0.386	0.0007	0.0007
Hybrid	9000	10000	1.300	0.0020	0.0045
Hybrid	5145	7200	0.951	0.000115	0.004325
Hybrid	5647	14475	0.489	0.00045	0.001
Hybrid	8524	16687	1.277	0.0027	0.0052
Water	19695	7566	1.277	0.0274	0.0052
Water	31000	5500	1.250	0.0024	0.0020
Water	14500	8000	1.577	0.0319	0.0079
Water	6035	10000	0.100	0.0035	0.0002
Water	8000	7566	1.277	0.0085	0.0052
Water	3300	6000	1.651	0.0010	0.0139
Water	12144	1777	1.277	0.0381	0.0052
Water	16165	7566	0.579	0.0008	0.0020
Water	11819	6098	1.600	0.0014	0.0052
Water	2055	6000	1.816	0.0289	0.0353

Figure A2: Each well's values of q_o, n, and D values for both the first and second fracture used in the hyperbolic decline curves, which were calculated using a least squares best fit model to match the historical production data.



Figures A3: Shows the comparison between initial production for the first and second fractures, organized by second fracture type. Initial production values were those calculated for the decline curve analysis of the production of the wells. All of the fluids considered in the study have points on both the improved and un-improved side of the plot. This difference arises as an effect of length of time between the first and second fractures.

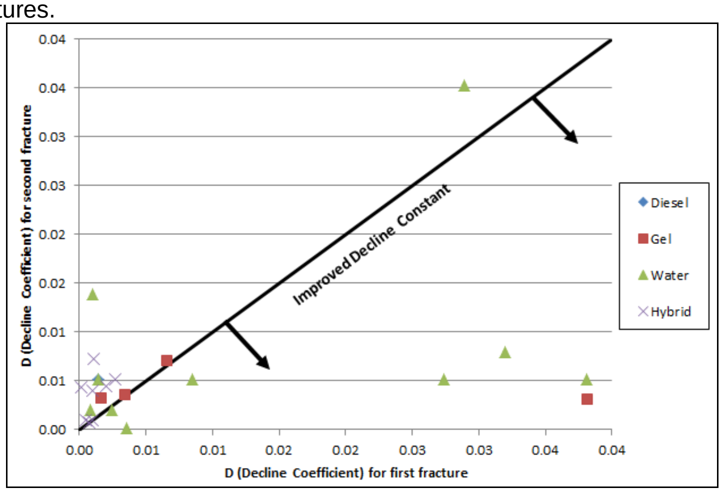


Figure A4: Shows the comparison between decline coefficient (D) for the first and second fractures, organized by second fracture type. D values were those calculated for the decline curve analysis of the production of the wells. Most of the wells considered actually had higher decline rates after the second fracture. Even though the decline coefficient suggest that the wells decline faster after refracturing, other effects in the reservoir allow a positive increased production.

Fracture Fluid	Δt months	Incremental Production MMscf	Average Gas Price $/MMscf	Incremental Gas Value $	Net Job Cost $M	Net Profit $M	Cost sum $M	Profit Sum $M	Average ROI $ Profit/$ Cost
Diesel	60	191.25	3500	669.38	170.00	499.38	170.00	499.38	2.94
Diesel*									
Gel	60	347.38	3500	1,215.82	190.00	1025.82	1677.30	1,677.30	1.00
Gel	60	81.77	3500	286.19	165.53	120.67			
Gel	60	137.52	3500	481.34	208.58	272.76			
Gel	60	108.29	3500	379.01	120.95	258.06			
Hybrid	60	291.43	3500	1,020.01	187.88	832.13	1333.51	3,931.64	2.95
Hybrid	60	49.74	3500	174.10	156.68	17.43			
Hybrid	60	180.50	3500	631.74	147.90	483.84			
Hybrid	60	83.00	3500	290.51	175.45	115.06			
Hybrid	60	236.05	3500	826.18	120.00	706.18			
Hybrid	60	80.42	3500	281.46	214.35	67.11			
Hybrid	60	217.69	3500	761.91	159.88	602.03			
Hybrid	60	365.50	3500	1,279.23	171.38	1107.86			
Water	60	-57.84	3500	-202.44	59.45	-261.89	810.62	1,883.65	2.32
Water	60	155.69	3500	544.93	73.00	471.93			
Water	60	135.50	3500	474.26	69.00	405.26			
Water	60	24.95	3500	87.32	45.63	41.69			
Water	60	148.47	3500	519.66	62.12	457.54			
Water	60	-8.67	3500	-30.34	73.60	-103.94			
Water	60	14.74	3500	51.59	86.34	-34.75			
Water	60	110.11	3500	385.40	92.00	293.40			
Water	60	161.79	3500	566.27	124.04	442.23			
Water	60	85.04	3500	297.62	125.44	172.18			

Figure A5. Summary showing incremental production created by the second fracture, incremental gas value, job costs for the second fracture, and ROI values for each of the wells used in the study. Please Figure 8 for a comparison of these values by fracture treatment type. Average ROI was computed using a sum of costs and profits for each of the fracture types.
*The second well was only fractured once, with a diesel fracture. Since no incremental volume could be calculated, the well was left out of further calculations.

Fracture Fluid	Incremental Production MMscf	Fluid Job Volume bbls	Net Job Cost $M	Job Cost $/bbl pumped
Diesel	191.25	1800	170.00	$94.44
Gel	347.38	4215	190.00	$45.08
Gel	81.77	3917	165.53	$42.26
Gel	137.52	4901	208.58	$42.56
Gel	108.29	2068	120.95	$58.49
Hybrid	291.43	3280	187.88	$57.28
Hybrid	49.74	3445	156.68	$45.48
Hybrid	180.50	3540	147.90	$41.78
Hybrid	83.00	3972	175.45	$44.17
Hybrid	236.05	3300	120.00	$36.36
Hybrid	80.42	3801	214.35	$56.39
Hybrid	217.69	3920	159.88	$40.78
Hybrid	365.50	3388	171.38	$50.58
Water	-57.84	3889	59.45	$15.29
Water	155.69	3977	73.00	$18.36
Water	135.50	4196	69.00	$16.44
Water	24.95	3722	45.63	$12.26
Water	148.47	3808	62.12	$16.31
Water	-8.67	4087	73.60	$18.01
Water	14.74	2102	86.34	$41.08
Water	110.11	2518	92.00	$36.54
Water	161.79	4433	124.04	$27.98
Water	85.04	4770	125.44	$26.30

Figure A6: Listing of the study wells and their incremental production, fluid job volume, net job cost, with job cost in $/bbl pumped calculated. While fluids are not the only costs associated with a fracture job, it was the focus of the study and thus provides a good normalized value. Water treatments are the overall cheapest option even though they have some of the highest fluid job volumes. The one diesel fracture was very high for the volume of the job. Gel fractures and hybrid fractures are very similar in their job costs, but while gels are a consistent price (with an increase in the fourth job), the hybrid fractures seem to decrease some over this time period. Hybrids are newer fracture types, which would explain the high initial cost of the fracture, but as technologies improve, companies will find a way to offer hybrid fracture treatments at a lower price for stimulation of wells.